Part 3 - RATE DESIGN

I. OVERVIEW

One of the necessary elements to restructuring the electric industry is to establish rates for T&D utilities. In this proceeding, the Commission will for the first time design rates for a T&D utility, an entity that has never before existed in Maine. In doing so, we must rely on existing law and traditional principles of utility rate design and apply them within changing circumstances.

The design of T&D rates in this proceeding is just one component in the State's larger effort to restructure the electric industry in Maine. The success of that effort must be the paramount concern. Therefore, we will design T&D rates in a manner that facilitates the transition to a competitive market for generation, as well as comporting with established rate design principles and goals. A critical aspect of the success of industry restructuring is public acceptance. Such acceptance may be jeopardized if, as a result of the design of T&D rates, there are significant bill increases or substantially disproportionate benefits among customer groups (such as substantial savings for some groups, while others see little or no savings) occurring at the beginning of retail access. The public is likely to attribute such bill impacts to retail competition, which could cause customer confusion and skepticism regarding electric restructuring and stimulate public resistance to industry change.

As a result, minimizing adverse bill impacts and customer confusion must be a primary objective in establishing T&D rates. However, we must also seek to design T&D rates to satisfy other legitimate ratemaking principles. It may be possible to improve CMP's T&D rate design without substantial adverse bill impacts relative to the status quo. The ability to make such changes, however, depends on many factors that are currently unknown and cannot be determined until we approach the date of retail access.

For these reasons, we will adopt what has been referred to as a "top-down" method as our initial approach to T&D revenue allocation and rate design. The goal of this approach will be to minimize adverse electricity bill impacts concurrent with retail access. We will also consider modifying the rate design resulting from the top-down approach so as to recover a portion of stranded costs through fixed charges, and to eliminate or reduce the inverted block structure of CMP's residential Rate A. We will effectuate these rate design changes if a sufficiently reliable bill impact analysis can be performed prior to March 1, 2000 that reveals that such changes can be made without substantial adverse impacts on customer electricity bills. These are the only modifications to CMP's rate design that we will consider at this time in the short-term. This conclusion is based on our assessment that such modifications are likely to be the only major rate design change that can occur in this case without risking unacceptable bill impacts, and upon our finding that the cost studies in this case do not support major shifts of revenue responsibility among customer classes.

As part of our design of T&D rates, we also adopt a new rate for standby service. The standby rate will be applicable to T&D backup service that CMP provides to customers with self-generation. We adopt a design for the standby rate that reflects to some extent the diversity of standby loads, that substantially reduces customers' responsibility for T&D costs, and that recovers stranded costs in amounts comparable to that recovered from full requirements customers of similar size and voltage.

II. DESIGN OF T&D RATES

A. Applicable Law and Principles

Before addressing the specific issues before us, we first review general rate design law and principles in light of the fundamental changes to the electric industry. As part of the restructuring Act, Maine's Legislature directed the Commission to design T&D rates "consistent with existing law, as applicable." 35-A M.R.S.A. § 3209(1). The only specific legislative directives regarding the design of electric rates are found in the Electric Rate Reform Act (ERRA). 35-A M.R.S.A. § 3151-3155. This Act, among other things, generally requires the Commission to: establish rates that relate more closely to the costs of service, promote maximum efficiency, reflect the marginal cost of service at different voltage levels and time periods, and consider rate design stability. Although the ERRA was enacted at a time of expected generation capacity shortages and rising electricity costs, and was premised on a vertically integrated industry with the monopoly provision of retail generation services,[1] its basic principles of basing rates on costs, promoting economic efficiency and maintaining rate stability certainly remain valid considerations for T&D rate design.

A more detailed articulation of electric rate design principles has developed through prior Commission decisions. *See Central Maine Power Company, Proposed Increase in Rates and Rate Design*, Docket No. 89-068 at 13-15, 21-27 (Jan. 30, 1992) (Docket No. 89-068 Order); *Central Maine Power Company, Investigation into Cost of Service of Customer Classes and Rate Design*, Docket No.

[1]As such, some of the language of the ERRA may be modified as part of the conforming amendments to Title 35-A. *See* P.L. 1997, ch. 316, sec. 11.

80-066 at 3-14 (Sept. 11, 1985); *Bangor Hydro-Electric Company, Investigation of Cost of Service and Rate Design*, Docket No. 80-108 at 1-7 (Jan. 10, 1985) (Docket No. 80-108 Order). Generally, the basic principles can be stated as follows:

- rates should be cost-based
- rates should reflect cost-causation
- rates should promote economic efficiency
- rates should be equitable in apportioning costs
- rates should be understandable, acceptable, and stable from the customers' perspective[2]

Although there is little dispute that these principles constitute the basic criteria for designing rates, they are often in conflict with one another.[3] It is their conflicting nature that makes utility rate design controversial and requires the exercise of sound judgment. Thus, setting utility prices can be considered partially art, partially science; it is an exercise of judgment informed by the technical and economic factors that influence underlying costs. In exercising this judgment, we remain aware that there are two primary aspects of designing rates: (1) allocation of the utility's revenue requirement among customer classes; and (2) the design of individual rate elements within classes. Traditionally, most of the emphasis in rate design cases has been on class allocation issues; the same has been true in this case. However, we recognize that intraclass rate design is as essential to satisfying ratemaking principles as interclass allocations.

[2]Rate stability in this context refers to the avoidance of substantial or unexpected rate changes, particularly rate increases.

[3]This articulation of rate design principles is consistent with Bonbright's commonly cited criteria. *See* James C. Bonbright**,** *Principles of Public Utility Rates,* 382-389 (2nd ed. 1988).

An examination of underlying costs is the centerpiece of any rate design proceeding. Two types of studies are generally used in such examinations: marginal cost studies and embedded cost studies. Marginal cost studies are primarily used to design rates that promote economic efficiency and mirror competitive pricing. Embedded cost studies are essentially based on equity concerns in that they seek to allocate existing costs among customers on a cost-causation basis. Cost studies are tools to be used in the design of rates and their results should never blindly be adopted as the appropriate basis for rates,[4] nor should such studies constitute the only ratemaking consideration.[5] Cost studies must be of sufficient quality and reliability to be used in the ratemaking process, and the overall reliability of such studies must be assessed and weighed in light of all legitimate rate design goals to determine the extent of their use.

It is upon these basic principles and considerations, that we will establish T&D rates in the restructured industry.

B. Short-Term Rates

[4]For example, if use of a marginal cost methodology results in the allocation of a substantial amount of generation-related costs based on the number of customers or use of the distribution system, then the result may not be equitable and should not be accepted without modification.

[5]Legislative language and Commission precedent refer to rates "based" on costs. There has never been a policy that rates should precisely "equal" costs for all customers. *See* Docket No. 80-108 Order at 4-5.

We have reviewed the record in light of the rate design goals and principles outlined above. As discussed, we conclude, that under current circumstances, considerations of public acceptance, bill impacts and customer confusion take precedence over other traditional rate design objectives. The success of industry restructuring must be the overriding goal. No party disagrees with this basic objective. However, the IECG argues that substantial revenue re-allocations and rate design modifications can occur without adverse bill impacts relative to the status quo. This assessment is based on the IECG's view of CMP's revenue requirements in conjunction with the projected 10% rate decrease resulting from the asset sale.

We agree with the IECG that CMP's rate design should be improved if it can be done without jeopardizing the transition to retail access. Unfortunately, we cannot now conclude whether this is possible. As discussed in Parts 1 and 2 above, many revenue requirement and stranded cost issues cannot be finally determined without additional review in Phase II of this proceeding. Moreover, the asset sale is now subject to litigation, making the resulting decrease uncertain. Additionally, a major component of the stranded cost calculation will not be known until the completion of QF output bidding pursuant to 35-A M.R.S.A. § 3204(4). Finally, standard offer bid prices, a key component of bill stability for many of Maine's consumers, will not be known until December 1, 1999; nor can we adequately project market prices due to delays in implementing the NEPOOL markets and the lack of experience with retail markets in New England.

Consequently, we cannot assess bill impacts now and, depending on developments, may not be able to adequately do so in time to implement rates on

March 1, 2000. For this reason, we adopt a top-down methodology as our initial short-term rate design.

To the extent bill impact analysis and customer acceptance considerations allow, we will set short-term rates to recover a portion of stranded costs through fixed charges and to flatten the current inverted structure of residential Rate A. We do not rely on the cost study information in the record for our short-term rate design decisions. Our review of the marginal cost study and embedded cost studies reveal that neither study supports significant reallocations among customer classes. As discussed in detail below, the underlying marginal cost calculations are not of sufficient reliability to base major shifts of revenue requirement. Moreover, the need for a "hybrid" approach in which distribution, transmission, and stranded costs are allocated based on different conceptual approaches raises serious concerns as to any efficiency gains that can be achieved through the marginal cost rate allocations presented in the proceeding. Additionally, although the embedded cost study was not thoroughly examined, its results do not suggest a need to modify class allocations. Thus, we will not require CMP's T&D revenue allocation to deviate from the results of the top-down method we describe in section II(C) below, nor will we adopt any rate design changes based on the results of the cost studies before us.

However, because stranded costs are, by definition, historically-incurred uneconomic costs, generally accepted principles of economics indicate that it is proper to recover them through fixed charges. With respect to CMP's inverted block residential rate, there is no cost basis for such a rate structure. Both findings can be made without reliance on cost studies. Accordingly, we conclude, based on a balancing of various rate design objectives, that CMP's short-term rates should move towards more fixed charge stranded cost recovery and a flatter Rate A to the extent bill impacts and customer acceptance considerations allow. In the event we do not have the information to conduct an accurate bill impact analysis in time to implement rates on March 1, 2000, or we conduct an analysis that shows unacceptable bill impacts, we will not modify the top-down rate design. If this is the case, we will consider making changes in these directions later in 2000 or early 2001.

C. Top-Down Approach

1. Positions Before the Commission

In the short-term, CMP proposes a "top-down" approach to allocating its revenue requirement and designing T&D rates for March 1, 2000. CMP advances this approach to minimize customer confusion and adverse bill impacts which it believes to be of paramount importance in promoting the success of industry restructuring. To implement its top-down method, CMP proposes to allocate the revenue requirement reduction resulting from its transition from a provider of bundled service to a provider of only T&D service (generation-related reduction) among customer classes based on their relative generation-related costs, and to reduce per-kWh charges to a level that produces each class' T&D revenue requirement. All other rate elements would remain unchanged. The reduction of only kWh charges is premised on CMP's belief that in the market, customers will generally pay for generation on a kWh basis.[6] In allocating the generation-related reduction, CMP would

[6]This method also advances one of CMP's longer-term objectives - to increase the recovery of costs through kW charges. *See* section II(H) below.

reflect generation cost differences among classes based on usage characteristics and line losses. Initially, CMP accounted only for line loss differences; but in response to the Bench Analysis, CMP modified its position to reflect usage characteristic-related differences. CMP also proposes to account for capacity reserve margins that providers must retain under NEPOOL rules.[7] Finally, CMP states that the best way to identify the factors affecting market costs of power for the different classes would be to rely on standard offer bid prices for individual customer classes. CMP notes, however, that the timing and structure of the current standard offer rule (Chapter 301) would reduce its usefulness for this purpose, but recognized that the structure of the rule is under review by the Commission in Docket No. 98-781.

The Public Advocate agrees with CMP that the fundamental goal of short-term T&D rates should be to minimize customer confusion and adverse bill impacts so as to promote an orderly transition to retail access. Accordingly, the Public Advocate generally supports CMP's top-down rate design and states that the approach should recognize customer class differences in load factors, load shapes, and provider marketing costs.

The IECG strongly opposes a top-down approach and advocates that customer class re-allocations should be made on the basis of CMP's marginal cost study using a "hybrid" allocation methodology, and that rates should contain higher fixed and demand charges. The IECG questions the goal of minimizing bill impacts, stating that the point of industry restructuring is to promote change. The IECG also

[7]CMP indicated that it would update its top-down approach if better information about the market price of electricity becomes known.

questions the Commission's ability to accurately predict market prices for customers so as to leave them in the same position as prior to restructuring. The IECG states that T&D rate design should be based on established cost causation principles and that maintaining the current rate design can only have an accidental relationship to the cost drivers of a stand-alone T&D utility. Throughout the proceeding, the IECG has stated that stability concerns can be addressed by using the available value from the FPL sale so that no customer class will be worse off than it was prior to the rate redesign.

2. Analysis and Conclusion

As discussed above, we will adopt a top-down methodology as our initial approach to setting T&D rates. We agree with CMP and the Public Advocate that promoting the success of industry restructuring by minimizing customer confusion and adverse bill impacts from T&D rate redesign must be our primary consideration. We will deviate from the top-down results only upon a determination of acceptable bill impacts

The IECG misinterprets the purpose of the top-down approach. The purpose is not to make electricity consumers indifferent to industry restructuring; the primary goal of restructuring is to make customers better off through the creation of a competitive generation market. The purpose of the top-down approach is to avoid customer confusion and dissatisfaction that would likely occur if there were major changes in CMP's rate structure or revenue allocation. Customers are unlikely to distinguish adverse T&D-related bill impacts from the effects of retail access. The point is to avoid confusion and controversy from the design of regulated T&D rates so that the unregulated generation market can develop unimpeded by public resistance. An effort to minimize overall adverse bill impacts at the beginning of retail access will not hinder the development of a competitive generation market, as suggested by the IECG, as long as it is not done by setting standard offer prices that are artificially held below market costs.

We note that the Legislature embodied the concept of a gradual transition to a competitive market by mandating a standard offer for all customers who do not choose a competitive provider. *See* Order Provisionally Adopting Rule, Docket No. 97-739 at 1,3 (Feb. 11, 1998). By utilizing a top-down T&D rate design in conjunction with our authority over the standard offer rate design, we can achieve substantial certainty that standard offer customers will not experience adverse relative bill impacts[8] without sabotaging the competitive market through artificially low standard offer prices. We recognize that we have less ability to affect relative bill impacts of customers not on the standard offer, but the top-down approach will minimize bill impacts relative to a substantial redesign of regulated rates. Finally, we note that we are not aware of any other state that has radically altered utility rate design at the time it introduced retail access for generation services.

Although we generally agree with CMP's implementation of the top-down approach, there are some aspects with which we disagree. First, the logic as we see it is not so much to mirror market prices, whatever they may be, but to

[8]There will, of course, be great concern if the level of the standard offer bids (as well as market prices in general) causes rates for Maine's consumers to rise substantially at the beginning of retail access. As suggested by the IECG, we have no control over this possibility. But we do have substantial control to moderate overall relative bill impacts among customers and customer classes; this is especially the case for standard offer customers.

recognize that CMP's revenue requirement is being reduced because CMP will no longer provide generation service; as such, the reduction should be allocated among customers in a manner reflecting their responsibility for CMP's generation-related costs. We will consider how best to achieve this result in Phase II. In the end, our logic may not reach a result that is very different than what is achieved by CMP's basic approach. However, we may reflect reductions in kW charges as well as kWh charges if it appears that doing so better matches generation costs with customer usage. As noted above, the objective of the top-down approach is to remove from current rates the revenues currently paid to CMP for generation. These revenues reflect the costs for both energy and capacity and, therefore, the reductions should also reflect both components.

In addition, we agree with CMP that the standard offer bid process presents a potential guide to implementation of the top-down approach. We are currently considering changes to our standard offer rule to allow greater flexibility for bidders to design prices among customer classes. *Investigation of Standard Offer Rate Design*, Docket No. 98-781. If the rule is modified in this regard, the bid prices would provide the basis for the top-down revenue reduction.

A final aspect of CMP's top-down approach with which we disagree is its starting point for certain classes. For most classes, CMP used current rate caps as the starting point for the generation-related reduction. However, for two classes (LGS-T and LGS-ST), CMP did not start with the rate caps, but instead used the current discounted rates applicable to those classes. We find that to implement the top-down approach, the starting point should be comparable for all customer classes by using current rate caps; CMP is directed to do so. As discussed in Part 1, we will treat current and future discounts from the rate caps separately.

D. Stranded Cost Recovery

Stranded cost are by definition uneconomic costs associated with past actions. They are sunk costs that are not affected by usage; as such, their existence should not impact how the system is utilized. It is, therefore, efficient from an economic perspective to recover them through charges that are not tied to usage. All parties appear to agree that economic efficiency is promoted by fixed charge recovery of stranded costs, because it allows usage sensitive charges to be set closer to actual on-going costs. This approach would also help reduce the incentive for uneconomic bypass which occurs when a customer uses an alternative to utility service, the cost of which is actually higher than the utility's marginal cost. An incentive for uneconomic bypass can exist when stranded cost recovery is tied to usage-sensitive charges.

CMP opposes fixing stranded cost recovery in the short-term because of bill impacts and implementation difficulties.[9] However, fixed stranded cost recovery is consistent with CMP's longer-term strategy. It is also generally consistent with the IECG's rate design proposal which would recover stranded costs through demand charges as a means to allow for consistent recovery for all requirements and standby customers.[10]

[9]The Bench Analysis asked CMP to explore stratifying classes with separate stranded cost fixed charges for each stratum. CMP concluded that, even with stratification, bill impacts might be unacceptable and that there would be administrative problems. Although we view stratification as a potentially useful means to pursue our goal of fixed cost recovery, we decline to adopt such an approach in this case because of complexities and possible customer confusion.

[10]IECG essentially proposes to eliminate kWh charges for most classes. *See*

As mentioned, the Commission may have flexibility to implement some rate design changes within bill impact and public acceptance limitations, if Commission-determined levels of T&D revenue requirement and stranded costs, combined with expected market prices and standard offer prices indicate sizable decreases relative to the status-quo. In this event, we will direct CMP to modify the results of the top-down revenue reduction to allow for a level of stranded cost recovery to occur through fixed charges. As discussed below, this will occur for all classes except residential Rate A.

E. Residential Rate A

The rate charged to most of CMP's residential customers (Rate A) has an inverted block structure. Specifically, the kWh charge increases by 25% after the first 400 kWhs of monthly usage. CMP proposes to gradually reduce this differential as part of its longer term rate design objectives, but does not propose to do so in the short term because of its concern over bill impacts. *See* section II(H) below. The Bench Analysis indicated agreement with CMP's position that Rate A should be flattened, stating that there is no cost-based support for an inverted block T&D rate structure. No party disputed the lack of a cost basis for an inverted rate.

We find that there is no cost basis for an inverted block T&D rate structure and will, thus, seek to flatten residential Rate A consistent with bill impact considerations. We conclude that flattening residential Rate A should have a greater priority for this class than implementing stranded cost recovery through fixed charges. The inverted block has been a source of customer confusion in the past and a

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section II(H) below.

flattening of the rate is likely to be more acceptable and understandable then introducing a fixed charge or increasing the minimum charge.[11] Due to bill impacts, we will not be able to both flatten the rate structure and introduce fixed stranded cost recovery in the short term. We, thus, must make a judgment as to the change that should have the greater priority. For the reasons discussed, we will seek to flatten Rate A in the short term[12] and defer fixing stranded cost recovery for residential Rate A customers to the longer-term.

F. Demand Ratchet

CMP proposed only one rate design modification to take effect on March 1, 1998. This change is to eliminate the demand ratchet for all non-station service customers. CMP would reflect a class' revenue currently collected through the demand ratchet in higher demand charges for the class. No party opposed this modification.

We will accept CMP's proposal to eliminate the demand ratchet. The demand ratchet has historically been a source of customer confusion. As proposed, the revenue lost from eliminating the ratchet should be recovered from the respective rate classes. This should occur through higher unit demand charges.

G. Charges for Generators Connected to System

[11]Residential Rate A currently has a minimum charge that applies to the first 100 kWhs of usage.

[12]Because it is unlikely that the standard offer rate design will have an inclining structure, it may be difficult to avoid actually increasing the inverted block differential of the T&D portion of the rate to prevent unacceptable impacts. To the extent possible, we will endeavor to avoid this result.

In its surrebuttal case, CMP sought Commission guidance on whether it should develop a new rate for generators who remain connected to its system, but who do not use the system to purchase power from the market or rely on CMP for standby service. CMP states that such entities derive operational advantages from being connected to a large, stable power system. These advantages include helping to stabilize customers' internal generation, and voltage and frequency stability when starting large motors. CMP argues that because such entities derive a benefit from being connected to CMP's system, they should pay a newly-established rate that includes a stranded cost component.

The IECG strongly opposes such a new rate, arguing that such generators receive no benefit from connection to CMP's T&D system, that it is actually generators (not the T&D lines) that provide voltage and frequency stability, and that such a charge would amount to an exit fee.

The question of whether generators obtain a benefit by virtue of connection to CMP's system is a question of fact that cannot be resolved on the current record. To the extent customers who generate their own power do obtain a benefit from being connected the CMP's system, it would be appropriate that they pay some charge for that benefit. As with all other CMP rates, such a charge should include some stranded cost component. Without additional facts in conjunction with a specific rate proposal, we cannot conclude whether a new rate is appropriate, how such a rate should be designed, or whether it would constitute an unlawful exit fee. We will make these necessary assessments if CMP comes forward with a new rate proposal in Phase II.

H. Long-Term Rate Design

1. Positions Before the Commission

Over the longer term, CMP proposes to move gradually to a T&D rate design that has higher fixed charges and lower usage-based charges. CMP's rationale is that a T&D utility's costs are essentially fixed in the short-term; once the system is built, costs do not vary with energy usage. Therefore, according to CMP, its longer term proposal represents a more cost-based rate design for T&D utilities. CMP also proposes, as part of its long-term approach, to flatten the existing inverted block structure of its residential Rate A, to eliminate seasonally differentiated rates and to simplify time-of-use periods consistent with marginal cost drivers. CMP would accomplish its longer-term rate design over time by applying rate increases to per-customer and per-kW charges and decreases to per-kWh charges. CMP suggested it would cap annual individual customer bill increases at approximately the rate of inflation, and noted that, because it expects rates to decrease, steady movement can be made towards an optimal rate design while maintaining a reasonable cap on rate increases.

The IECG generally agrees with CMP's rate design approach of greater fixed and lower usage charges. Specifically, the IECG proposes that the entire customer-related revenue requirement be recovered through fixed monthly customer charges[13] for all classes other than residential Rate A, and that distribution and transmission revenue requirements be recovered through demand charges for those

[13] The IECG believes this will simplify the eventual unbundling of billing and metering costs.

classes with demand meters; thus, its proposed rate design would maintain kWh charges only for residential and small commercial customers.

The OPA disagrees with CMP's long-term objective of increasing fixed charges. OPA witness Anderson testified that some costs associated with the T&D system are energy-related and that it would not necessarily be more efficient to have higher fixed charges because it might discourage conservation.

2. Analysis and Conclusion

We agree with some of CMP's longer-term goals. As discussed above, we will attempt to flatten the currently inverted residential Rate A in the short term consistent with bill impact consideration; if this cannot occur, the rate should be flattened as part of longer-term rate design strategy. We also adopt CMP's proposal to eliminate seasonally differentiated rates as lacking a sufficient cost-basis. We agree that time-of-use rates should be maintained as a proper price signal that reflects the underlying costs of the T&D system, but support CMP's examination of simplifying time-of-use rates. None of the parties explicitly objected to the merits of these changes.

The record, however, does not justify a general finding that we should move to increasingly fixed T&D charges. CMP's only justification for this position is that most T&D costs are fixed in the short-run. However, it is often the case that although a cost is fixed, it may nevertheless be related to energy usage. For example, we have consistently considered the majority of the fixed capital costs of a baseload generation plant as energy related. Accordingly, it may not be either efficient or equitable to recover costs through non-usage charges simply because the costs are fixed. The IECG's position is based on its views that transmission and distribution costs are driven only by peak demands. As discussed in section III(B) below, we disagree with this premise.

It may be that a detailed examination of CMP's costs would justify some movement to higher fixed charges for T&D-related costs. However, the record does not reveal the extent of such movement and we make no finding in this regard. Over the next several years, bill impact constraints would likely prevent us from moving to higher fixed charge T&D cost recovery, while also satisfying our goals of fixed stranded cost recovery and flattening Rate A. However, as stranded costs are recovered over time and rates are correspondingly decreased, it would be appropriate to consider the cost basis for increasing fixed T&D charges.

Finally, we are supportive of CMP's gradual approach to achieving desired rate design changes. We do not, however, adopt any particular schedule or maximum cap related to future rate changes. The reasonableness and acceptability of rate changes will necessarily depend on the circumstances existing at the time. For this reason, we will determine the appropriate degree of rate design changes as the issue arises in future proceedings.

III. COST STUDIES AND CLASS ALLOCATIONS

In this section, we discuss the cost study and revenue allocation issues raised in this proceeding. CMP presented both marginal cost and embedded cost studies. We explain why neither study supports customer class revenue reallocations on March 1, 2000 and provide guidance for future cost studies. Next, we address jurisdictional issues regarding transmission cost allocations. Then, we discuss and adopt a method for future stranded cost allocation. Finally, we address the future use of marginal cost and embedded cost studies as the basis for T&D cost allocations.

A. General Methodological Considerations

The restructuring of the industry requires us to carefully examine costing and allocation methodologies; this is especially the case through the transition period in which stranded costs must be recovered. The transition from vertically-integrated electric utilities to T&D utilities raises novel questions of cost allocation. We must, therefore, consider new methodologies and re-examine existing approaches as we establish rates in a restructured environment.[14]

CMP acknowledged the difficulty in addressing appropriate costing and allocation methodologies and notes that a top-down approach would avoid the need to resolve such issues at the current time. Instead, decisions on T&D costing and allocation could be made later when Maine and other jurisdictions have experience with

[14]For example, the calculation and allocation methodologies used in the past for T&D costs are of much greater consequence when establishing rates for a T&D utility than for an integrated utility. In the past, the allocation of generation-related costs received the most attention because it was such a large component of electric utility costs. Accordingly, existing methodologies must be scrutinized before they are used to establish T&D rates. *See* Docket No. 95-052 Order at 7-8 (regulatory policy on cost methodologies is not static, builds on prior determinations).

T&D-only utilities and are in a better position to determine the cost allocation approaches that make the most sense.

In the longer-term, CMP recommends what has been referred to as a "hybrid" methodology[15] to allocate its costs among customer classes. In the past, the Commission has employed, as a starting point for class revenues, a marginal cost allocation methodology in which each customer class is responsible for its class marginal cost with the difference between total revenue requirement and total marginal cost allocated using the equi-proportional marginal cost (EPMC) reconciliation methodology. *See Maine Public Service Company, Proposed Increase in Rates (Rate Design)*, Docket No. 95-052 at 37-40 (June 26, 1996) (Docket No. 95-052 Order); Docket No. 89-068 Order at 21-27. Due to industry changes, CMP proposes to deviate from the "pure" marginal cost/EPMC methodology and employ the following hybrid methodology:

- customer and distribution costs are allocated based on relative class marginal cost reconciled to total customer and distribution embedded costs through the EPMC methodology.

- transmission costs are allocated using FERC's 12-CP embedded cost methodology.

- stranded costs are allocated on the basis of relative class revenue contributions at the existing capped rates.

The Company also filed an embedded cost study for informational purposes, but does not advocate its use in this or future proceedings.

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[15]The "hybrid" terminology has been used in this proceeding to distinguish between a "pure" marginal cost/EPMC methodology used in the past with proposals, such as CMP's, that employ differing methodologies for different categories of costs (i.e., distribution, transmission, and stranded costs).

The IECG agrees with the Company that a hybrid methodology should be adopted. It accepts CMP's methodology for allocating distribution and transmission costs, but disagrees with the Company's allocation of stranded costs; the IECG proposes to allocate stranded costs 50% on energy usage and 50% on demand.

The OPA seriously questions continued reliance on marginal cost methodologies in a restructured environment, arguing that it is difficult to achieve the efficiency goal of marginal cost allocations using a hybrid approach and that it is very difficult to accurately quantify marginal costs associated with distribution. The OPA instead recommends using an embedded cost method to allocate T&D costs. With respect to stranded costs, the OPA proposes a third approach in which the costs would be allocated solely on energy.[16]

We agree with the Company that industry restructuring raises substantial challenges in determining costing and allocation methodologies. We also agree that our prior use of a pure marginal cost/EPMC methodology must be abandoned in favor of a hybrid approach. A pure marginal cost/EPMC approach would result in the allocation of generation-related stranded costs based on the marginal customer and distribution costs; a result that would clearly be inequitable. We, therefore, need to develop new allocation methodologies to be used in the future.

Our decision to employ a top-down approach and not to rely on the cost studies in establishing CMP's short-term rate design is not a result of a desire to avoid these difficult issues; rather for the reasons discussed earlier we adopt a top-down approach on its own merits. We do, however, agree with CMP that the adoption of a

[16]The Bench Analysis raised other approaches to stranded cost allocations. These are discussed in section III(E) below.

top-down approach does have a secondary benefit of allowing the parties and the Commission an opportunity to more fully address the methodological issues raised in this proceeding. In the following sections, we identify and discuss issues that will need to be considered in future proceedings.

B. Marginal Cost Study

As stated, we find that the marginal cost study presented in this case lacks the necessary reliability to support substantial shifts in revenue requirement allocations among customer classes.[17] We discuss below our rationale for this finding and identify areas that must be addressed in the future to improve the reliability of the marginal cost estimates.

At the outset, we generally review CMP's methodology for estimating unit marginal costs and allocating total marginal costs to customer classes. Under its approach, referred to as the "vintage plant" methodology,[18] CMP uses a regression analysis that relates annual investment in distribution plant to changes in its annual system coincident peak (CP)[19] using 60 years of historical data. This produces a

[17]As noted above, a cost study must be of sufficient reliability to be used in establishing rates. It is inappropriate to use a study that is seriously flawed simply because it provides the only estimates presented in the record. *See generally*, Docket No. 95-052 Order at 4-6, 26-29, 41-43 (reliability of studies taken into account in designing rates).

[18]In a prior proceeding, the Commission adopted this type of regression analysis which relates costs to loads, and stated a preference for use of NCPs rather than CPs. *Investigation of Central Maine Power Company's Resource Planning, Rate Structures and Long-Term Avoided Costs,* Docket No. 92-315 at 63 (Feb. 18, 1994). In a later proceeding, the Commission indicated that it was not prepared at that time to endorse the vintage plant method, over other methods, as a matter of general rate design policy. Docket No. 95-052 Order at 22-23.

[19]The annual system coincident peak is the amount of demand at the hour during the year when the sum of all customer demands is the highest.

marginal distribution plant unit cost that the Company then converts to a total Company marginal distribution demand cost. This total cost is allocated among classes based on each class' average of CPs and non-coincident peaks (NCPs).[20] Marginal distribution O&M costs are estimated using a single year (1996) of actual expenses. CMP treated marginal meter and service drop costs as customer-related and calculated the costs consistent with previous studies.

There are two primary flaws with CMP's study: the marginal distribution plant unit cost estimates produced through the regression analysis; and the allocation of total Company marginal distribution costs among customer classes. Issues regarding O&M expenses, as well as other miscellaneous issues discussed below, are less serious, but should be examined in future cost studies.

1. Regression Model

The Company's regression model suffers from two basic conceptual problems. First, the Company uses recent experience to separate its system coincident peak loads into the amounts at transmission, and primary and secondary distribution voltages. These amounts are assumed to be constant in a relative sense over the 60-year historical period. CMP has essentially divided annual system coincident peak arbitrarily into three categories, which it sets as constant over time. As a result, the regression analysis really estimates only one equation -- total distribution plant investment as a function of the annual system coincident peak demand. The primary and secondary distribution equations are no more than

[20]The non-coincident peak is the highest demand of a customer class during a time period.

proportional scalars of this one equation and thus are not indicative of the relationship between investment in primary and secondary distribution plant and load. In other words, the same results could be obtained for the primary and secondary equations by taking a simple fraction of the results of the system CP equation, because they are not independently determined.

Second, an even more serious problem is that the Company's approach is premised on the wrong equation. Witnesses in this proceeding agreed that distribution plant investment is driven, for the most part, by local area peaks. As a result, we find no basis to conclude that it is changes in the system CP that determine adjustments in the amount of distribution plant. It is likely that what the Company's regression equation actually captures is that distribution plant investment grew over time as did the system coincident peak (along with most other aspects of the utility's operation). This point is supported by Mr. Anderson, who testified that he obtained equally significant statistical results by simply regressing distribution plant investment on time. Thus, we cannot conclude that the Company's regression analysis supports its basic premise that distribution costs are driven by peak demands at the time of the system peak.[21] We are also concerned that the Company has not provided evidence of the absence of autocorrelation problems with its equations.[22] Given Mr. Anderson's

[21]In responding to intervenor arguments regarding diversity in establishing standby rates, CMP stated that system peak "is not relevant for individual distribution circuits." CMP Reply Brief at 72 n.37. (emphasis in original)

[22]Autocorrelation refers to the error terms associated with observations in a given time period that carry over to future time periods. This represents a violation of one of the underlying assumptions of ordinary least squares regression, that the error terms are statistically independent.

results using timetrend analysis, it is reasonable to expect a high degree of autocorrelation of the error terms in the Company's equations. Correcting for such autocorrelation could be expected to adversely affect the statistical significance of the estimated coefficients, i.e., the marginal investment estimates.

The Company attempts to account for the impact of local area peaks on marginal distribution costs by allocating these costs among the classes in part on the basis of class NCPs[23] as well as CPs. However, this is not a satisfactory resolution in that it does not correct for the fact that the Company's marginal distribution unit cost estimates remain premised on an assumption that they are driven by usage at the system CP.

For the reasons discussed, we can place little reliance on the Company’s distribution plant investment regression estimates, which provide the major component of the Company’s marginal distribution costs.

2. Planning Criteria for Distribution Plant Additions

The Company's unit distribution plant estimates and class allocations are of greater concern in light of its stated planning criterion for the distribution system. The Company maintains that there are no diversity benefits in planning for distribution capacity to serve large loads (above 400 kW).[24] This position further calls into question the reasonableness of the regression estimates of unit marginal costs derived using system coincident peak. Based on CMP's stated planning

[23]NCPs have been used in prior studies as a proxy for local area peaks.

[24]This matter was raised by CMP in justifying its standby rate proposal and we discuss it in detail in section IV below.

criteria, the relevant loads would be the coincident local peaks of small customers and the maximum potential demands of large customers. Moreover, the Company's stated planning criterion leads to the conclusion that its marginal cost study erroneously allocates distribution costs because it uses relative class CPs and NCPs, rather than maximum potential demands for classes above 400 kW and the relevant coincident demands of classes below 400 kW.

The Company states that distribution capacity investments to meet the load of a large customer on a distribution circuit are driven by that customer's maximum potential demand. The Company treats larger customers in the same manner for planning purposes, regardless of whether they are a standby or full requirements customers (sufficient capacity is maintained to meet 100 percent of a larger customer’s load without regard for diversity). Based on the Company's planning criterion, the load that drives distribution investment is the coincident load of all small customers on a circuit plus the maximum potential individual loads of large customers on the circuit, rather than system coincident peak as assumed in CMP's regression analysis. Accordingly, in conducting future cost studies, the Company should explore methodologies that account for the relationship between distribution investment and its stated planning criterion.[25] The Company should also reflect this planning criterion in its allocation of distribution costs among customer classes.

3. Energy Relationship to T&D Costs

a. Positions Before the Commission

[25]Consistent with our discussion below, the Company should also develop costing methodologies that account for the relationship of energy usage to marginal distribution costs.

The Bench Analysis raises the general question of whether some portion of T&D costs should be allocated to classes based on energy use. The issue was raised in the Analysis, in part, because CMP's approach does not allocate any of the costs of the T&D system according to the use of energy, even though the system exists to deliver kWhs of energy to end users. The Bench Analysis states that, although incremental costs are incurred to meet elevated demands, this does not mean that all distribution costs are demand-related. Such an assumption would lead to the conclusion that customers who never use the system during peak hours should be able to use the system for free.

The Bench Analysis states that distribution plant was constructed primarily to deliver energy to customers during all hours of the year, not just at the times of the peaks; the system exists and related costs are incurred to deliver electricity to customers whenever it is desired. The Analysis postulated that, if energy was needed only several hours each year, it is likely that the current T&D system would not have been constructed; consequently, it is proper that some significant portion of the capital costs of the T&D system should be allocated on energy use. The Bench Analysis suggests that CMP's 65% system load factor and 60% load factor for distribution-voltage customers provide a logical basis to determine the energy share. The load factor is the ratio of average demand to peak demand; average demand is also a measure of energy use. Therefore, the Bench Analysis states that it is reasonable to use load factor to divide T&D costs into energy-related and peak demand-related components. This is because, if there were no variance in the hourly demands on the system, its capacity would have to be designed to meet the annual energy demand (i.e., average demand); costs to meet additional demands are appropriately considered demand-related. Rather than relying on load factor, however, the Bench Analysis proposed to deviate somewhat less from past practice by splitting costs on a 50/50 basis between energy and demand.[26]

CMP and the IECG criticize the suggestion that some portion of T&D plant should be allocated on energy. The other parties did not address this issue. With respect to transmission, the Company states that costs must be allocated according to FERC’s methodology, which uses a 12 CP allocator. We discuss the implications of FERC's jurisdiction over the allocation of retail transmission cost in section III(D) below.

The Company's position regarding distribution costs is that upgrades to the system are made solely in response to peak demands. As a result, the marginal cost of distribution is appropriately defined as the additional investment made in response to an increase in peak demands. In the Company's view, energy use has no responsibility for marginal distribution costs, and an energy allocation would have no cost basis. Finally, the Company notes that no jurisdiction has allocated an electric utility's distribution costs on the basis of energy usage.

The IECG recognizes that the delivery of energy must be taken into account in planning the T&D system. However, the IECG argues that, the energy component of system expansion decisions relate to the analysis of how probable it is that certain demands will, in fact, have to be met. Therefore, according to the IECG, the energy aspect of system planning is already incorporated in the demand

[26]The Bench Analysis proposed that this allocation be used whether an embedded or marginal study is used to determine the costs of T&D.

component through the recognition of class diversity and reliability standards; as a result, T&D investments are already limited to items that can be justified on an energy basis.

b. Analysis and Conclusion

For the reasons discussed below, we find that it is appropriate to allocate portions of the T&D system costs on the basis of energy. We have previously decided that certain high voltage transmission line investments are energy-related and thus not marginal with respect to demand. Docket No. 89-068 Order at 38-39. The question before us is whether other portions of the T&D system are energy-related and marginal with respect to energy usage.

In the long-run, when all costs are considered variable, it seems clear that some portion of T&D system costs is marginal with respect to energy. When decisions are made whether to build a particular portion of the distribution system or whether to build an integrated system at all, the amount of energy over which the costs of the system investment can be amortized must enter the decision. Thus, it is the use of energy, to some significant degree, that results in the investment to construct the system.

We recognize that our discussion refers to a longer-run marginal cost concept and, that in the shorter-term, distribution investments are primarily demand-driven. In our order adopting marginal cost-based allocations, we found that a more intermediate-term marginal cost approach (that looked over a reasonable planning period) to be appropriate. Docket No. 89-068 Order at 29-33. However, the Company's regression methodology based on 60 years of historical data yields what can be considered a longer-term marginal cost. To the extent longer-run marginal costs are considered, we find that some portion of distribution costs are marginal with respect to energy and should thus be allocated on the basis of energy.

However, even from a shorter-run marginal cost perspective, whereby distribution investments are considered primarily demand-related, an allocation of a significant portion of marginal T&D costs on energy leads to a more equitable allocation of CMP's revenue requirement. Embedded distribution costs are more than double marginal distribution costs, resulting in a relatively large reconciliation amount. The allocation of a reconciliation amount always raises questions of equity and cost-causation. Even if we assume that CMP incurs incremental distribution costs only from loads at the time of peaks, this does not mean that the entire reconciliation amount should be allocated on the same basis. The issue becomes how to allocate embedded costs that were incurred with a long-view of providing a system that delivers energy in a reliable fashion to all customers at all times of the year.[27] Our view is that even if all marginal distribution costs are related to peak usage in the short or intermediate term, it would still be equitable and consistent with cost causation principles to allocate a portion of the reconciliation amount on energy.

The Bench Analysis presented one approach to reflecting energy responsibility for CMP's distribution system using CMP's marginal distribution cost estimates. However, the method used in the Bench Analysis, which relied upon

[27]The Company raises a similar concern in response to station service customers arguments: "In sum, the short answer to the intervenors claim that they add no incremental (short-term) marginal cost is: so what? The real issue is the long-view, and who should pay the <u>embedded cost</u> of the system." (emphasis in original). CMP Reply Brief at 75.

distribution unit costs per system CP and allocated a portion of those costs on an energy basis, suffers from the same flaws we noted above for CMP's allocation of distribution costs. We, thus, direct CMP to explore methodologies that identify the relationship of energy use to marginal distribution cost in estimating unit and total costs, and how to properly allocate those costs among customer classes.

Finally, in response to the IECG, we agree that system planners take class diversity and the need for reliability into account before sizing and building T&D facilities. However, this does not address the costing issue. The IECG appears to agree that T&D investment will not be made unless there is enough energy usage throughout the year to support the investment, but argues that the facilities are designed to meet demands and are not sized any differently depending on energy usage. As we discussed, although T&D facilities are sized to meet peak demands, they are constructed to meet both energy as well as peak requirements. Thus, some portion of the system costs should be considered marginal with respect to energy. This view is not contradicted by the IECG argument that class diversity and reliability are taken into account in sizing and building the system.

4. Miscellaneous Issues

Three additional issues were raised regarding the Company's marginal cost study. OPA witness Anderson questions CMP's use of recent average O&M expense as a proxy for marginal O&M. Mr. Anderson's concern is that this approach assumes there are no economies of scale or scope and, thus, it overestimates this cost component. The Company responds that there is no empirical evidence that there are such economies and that marginal O&M costs are less than average O&M costs. The Company also argues their method is regularly used and is recommended by NERA. Our view is that the Public Advocate has raised a legitimate issue that should be fully addressed in the next cost-of-service proceeding. Specifically, CMP should consider whether such economies exists and, if so, how they should be measured.

The Bench Analysis questioned the Company's use of only a single year to estimate marginal O&M costs rather than the 5-year average used in previous cases. The Company notes that this change was made because Mr. Caron and Ms. Dufour performed a thorough examination of its 1996 costs as part of their separations study and this analysis was not performed for any other year. Although this explanation is not unreasonable, the Company should revisit the question of how best to estimate O&M costs, including the issue of the existence of scale and scope economies in the future cost studies.

Finally, the Bench Analysis questioned the Company’s use of system probability of peak rather than class NCPs to assign distribution costs to rate periods. The Company argues convincingly that it is the time pattern of loads on local distribution circuits that is relevant. CMP states that, in this service territory, distribution equipment normally does not serve customers from a single class. As a result, it appears inappropriate to use class NCPs to assign these costs to rate periods. However, we are not convinced that system probability of peak properly assigns these costs to periods. System-wide load variations may have little to do with these variations on local circuits. Indeed, selected probability of peak data for individual substations provided by the Company show significant variation in the time patterns of local loads. It may be that, absent the ability to reflect time variations at the local level, there is no basis to vary charges by time of day. We direct the Company to consider this issue in greater depth when it prepares its next marginal cost study.

C. Embedded Cost Study

As noted above, relatively little attention was focused on the Company's embedded cost study. A great deal of additional scrutiny of the study would need to take place before the results could be relied upon for class allocations. Nevertheless, we note that the results of the Company's study, either with or without a modification to include an energy allocation of 50% of the T&D costs, do not support a significant re-allocation of revenues among classes.

The Bench Analysis and Public Advocate did raise several issues that we discuss below. Some of these issues are the same as those raised regarding the marginal cost study and so we need not repeat the discussion in detail. We will limit our attention to three issues: (1) an energy allocation of T&D costs; (2) the appropriate demand allocator for large customers; and (3) the appropriate allocator for A&G expense.

1. Energy Allocation

For the reasons discussed above in the context of the marginal cost study, it is appropriate to allocate a substantial portion of T&D embedded capital costs on the use of energy. Although the Company seems to argue that there is no cost basis for such an allocation, its major objection no longer applies. CMP's fundamental argument is that an energy allocation would amount to an abandonment of marginal cost principles. While we do not agree with the Company's characterization in this regard, the argument becomes moot in the context of an embedded cost study whose goal is to allocate historic costs on a cost-causation basis. Accordingly, the question becomes what usage characteristics caused T&D plant to be built in the first place; the argument that energy use bears some significant responsibility is persuasive. We note that the difficulties discussed above regarding the estimation and allocation of energy-related marginal distribution costs do not relate to an embedded cost study in which the distribution system revenue requirement is allocated among classes. In this context, it is appropriate to simply allocate embedded distribution plant costs on both energy and demand using the Company's load factor as the basis for the split.

2. Demand Allocator for Large Customers

As stated, we accept the Company's representation that distribution capacity is planned to meet the maximum potential load of large customers without regard to the diversity of those loads. Accordingly, we conclude that distribution demand- related costs have been improperly allocated in both the Company's marginal and embedded cost studies. The allocation should be based on how the Company actually plans and constructs the system, because this is what drives costs. The appropriate distribution demand allocator, therefore, should be the sum of coincident demands of small customers on local circuits plus the sum of the maximum potential demands of large customers. If no costs are allocated on energy, the appropriate allocator should be small classes' NCPs plus the sum of the individual customer maximum demands of classes of customers with demands greater than 400 kW. The appropriate allocation is less clear under an approach where half of these costs would be allocated on energy. This is because maximum potential demands already place weight on the loads to be served at hours other than peak hours. Whether and how the maximum demand-related planning criteria should be combined with an energy allocator is an issue that should be addressed when the Company next files cost studies.

3. Allocation of A&G Expense

OPA witness Anderson challenged the Company's assumption that all A&G expense should be allocated to classes in proportion to payroll expense. He asserts that the Company's own separation study demonstrates that approximately 30% of these costs should be allocated on plant rather than payroll expense. He argues that the use of payroll expense will result in overcharging the residential class for these costs. The Company counters that its payroll method is one standard allocation recognized by NARUC. It further contends that its method is an allocation based on assumptions, rather than direct cost causation and that any alternative to allocate A&G, such as suggested by Mr. Anderson, would simply be based on a set of new assumptions.

The Company's argument does not persuade us to reject Mr. Anderson's alternative. Given that allocations of non-direct costs require the application of assumptions and logic, our view is that it is appropriate to evaluate the evidence provided to support the underlying assumptions. We should not simply accept a formulaic approach because it is one of the methods presented in the NARUC Cost Allocation Manual. We direct the Company to account for the appropriate plant-related portion of A&G expense in its next embedded cost study.

D. Transmission Costs

1. Jurisdiction

CMP asserted throughout this proceeding that FERC has exclusive jurisdiction over retail transmission rates by virtue of the State's decision to unbundle generation as a separate product. The IECG agrees with this position and no party disputed the position. The Bench Analysis questioned whether FERC would have jurisdiction over the transmission component of a "bundled" retail T&D service in which transmission is not unbundled as a separate retail product.

We have carefully reviewed FERC's discussion of this matter throughout its Order No. 888[28] and have concluded that, although its language is often ambiguous, FERC's intended conclusion is that it has exclusive jurisdiction over the rates, terms, and conditions of retail transmission rates when generation is unbundled and offered as a retail product separate from "delivery service." However, FERC has explicitly stated a willingness to defer to the needs of state retail competition programs. CMP claims that this deference was intended to include only minor deviations from FERC open access tariffs and transmission pricing policies. In our view, CMP's interpretation of FERC's statements is overly-restrictive; FERC has left the door open for utilities and states to request retail transmission rates, terms and conditions that meet state needs and policies. It appears that, upon reasonable justification, FERC will provide substantial deference regarding retail transmission filings made pursuant to state retail competition programs, as long as they are consistent with FERC open access policies.

[28]FERC Docket Nos. RM95-8-000, RM94-7-001 (April 24, 1996.)

In Order No. 888, FERC explained why its authority attaches only to unbundled, but not bundled, retail transmission in interstate commerce by stating:

> when transmission is sold as part and parcel of the delivered product called electric energy, the transaction is a sale of electric energy at retail. Under the FPA, the Commission's jurisdiction over sales of electric energy extends only to wholesale sales. However, when a retail transaction is broken into two products that are sold separately (perhaps by two different suppliers: an electric energy supplier and a transmission supplier), we believe the jurisdictional lines change. In this situation, the state clearly retains jurisdiction over the sale of the power. However, the unbundled transmission service involves only the provision of "transmission in interstate commerce" which, under the FPA, is exclusively within the jurisdiction of the Commission. Therefore, when a bundled retail sale is unbundled and becomes separate transmission and power sale transactions, the resulting transmission transaction falls within the Federal sphere of regulation.

Id. at 246-247. In other portions of the Order, FERC defines retail wheeling services as the delivery of electric energy that includes two components: transmission and local distribution. FERC asserts jurisdiction over transmission facilities, while indicating that states have jurisdiction over local distribution facilities. *Id.* at 229 n.515, 516, 244-253.

The FERC language throughout the Order, taken as a whole, reveals an intent to exercise exclusive jurisdiction over the rates, terms, and conditions of retail transmission component of delivery service, if generation is unbundled and offered as separate product. As a result of its jurisdiction, FERC states that rates, terms and conditions of retail transmission must be filed with the agency. *Id.* at 252.

Despite its exercise of exclusive jurisdiction, the FERC repeatedly emphasized its desire to promote state/federal cooperation and rely on state expertise, as well as a willingness to defer to state retail competition programs where appropriate.

> While the Commission cannot simply turn over its jurisdiction for the states to implement, we understand the concerns raised by many state regulators and believe that deference to state commissions with regard to rates, terms, and conditions [for retail transmission service] may be appropriate in some circumstances . . . .

Id.

The FERC explicitly stated that, although it "generally expects" unbundled retail wheeling customers to take service under the same tariff as wholesale customers, it may be appropriate to have a separate retail transmission tariff with different terms if unbundling occurs as part of a state retail access program.[29] *Id.* at 252. The FERC stated:

> In such situations, the Commission will defer to state requests for variations from the FERC wholesale tariff to meet these local concerns, so long as the separate retail tariff is consistent with the Commission's open access policies and comparability principles . . . .

Id.; see also *Id.* at 98.

In addition to stating its general willingness "to give deference to state recommendations regarding rates, terms, and conditions for retail transmission service," *id.* at 98, the FERC specifically references several areas where deference may be provided: transmission cost allocation between retail and wholesale customers, allocation of costs between transmission and distribution facilities, and the determination of transmission and distribution facilities for jurisdictional purposes. *Id.* at 251.

[29]FERC stated that unless a separate retail transmission tariff is on file, its pro forma tariff must include retail transmission customers as eligible. *Id.* at 98.

As long as a state fosters FERC's general policy of promoting electric market competition (as Maine's restructuring effort clearly does) and state recommendations are consistent with FERC's policy of non-discriminatory, open transmission access, the FERC is reasonably likely to defer to state views regarding the implementation of their retail access programs.[30] This is especially likely to be the case in areas of traditional state concern, such as customer class allocations and rate design for retail ratepayers taking a regulated service from its local utility. As stated above, the FERC has expressed a willingness to defer to states regarding cost allocations among wholesale and retail customers, and among transmission and distribution facilities; it is thus reasonable to assume a similar deference regarding a state's allocation and rate design among retail customer groups.

It appears that deference to states' policies regarding the allocation of costs and rate design in the context of establishing a T&D utility's rates for retail service within its local territory would not be inconsistent with FERC open access policies or offend its comparability principles. If a retail customer in another state desires to purchase transmission through CMP's territory so that it can access a remote generation provider, that customer would be eligible to purchase under CMP's pro forma open access tariff. This would provide for comparability between retail and wholesale transactions that require transmission through CMP's territory. However, in this case, we are establishing combined T&D utility retail rates for a monopoly service

[30]The FERC stated that "[a]lthough the Commission believes its Final Rule will accommodate retail competition . . . our policies relate only to the bulk power market and not traditional state regulation of the retail market. *Id.* at 248.

applicable to customers within the utility's local service territory. Because all retail customers within the service territory will purchase bundled T&D service from CMP at regulated rates, customer class revenue allocations and intraclass rate design will not implicate FERC's non-discriminatory open transmission access policies.

The precise implications of FERC's jurisdiction over retail transmission to the issues in this proceeding are unclear. It appears that CMP will have to make a retail service filing at FERC,[31] otherwise all its retail customers (including residential and small business customers)[32] would have to take retail transmission service under the rates, terms and conditions of its pro forma open access tariff. CMP, however, never explained the implication of FERC jurisdiction in light of its top-down approach to rate design. One option may be for CMP to file its retail T&D tariff, including terms and conditions of service, at FERC without an explicit unbundling of transmission rate. Another approach might be to file unbundled retail transmission rates (with corresponding terms and conditions) consistent with the top-down T&D rate design; in such a case, the rates in this case could be established on a residual basis as the difference between the top-down rates and the unbundled transmission rates. This matter will be addressed in the transmission investigation discussed below.

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[31]As noted in Part I, it appears that CMP will have to file at FERC to establish its transmission revenue requirement.

[32]Under the FERC tariff, these customers would have to be charged for transmission through a per-kW charge which would not be feasible because these customers do not have demand meters. Accordingly, we presume FERC will allow this deviation from its tariffs even though the conversion to a kWh charge would have the necessary effect of re-allocating costs within the class relative to FERC's 12 CP allocation, an action that CMP insists FERC would not allow as between rate classes.

With respect to future cost of service proceedings, we anticipate that FERC would defer to our retail costing and rate design policies. If so, transmission cost allocation and rate design would be consistent with our policies stated in this and future orders.[33] If FERC acts to pre-empt our policies in this regard, then transmission costs would be separately allocated within the type of hybrid methodology proposed by CMP and the IECG.

2. Investigation

Based on our conclusion that FERC has asserted jurisdiction over retail transmission when generation is unbundled, we will open an investigation into transmission matters, as proposed by CMP.[34]

As mentioned above, FERC has sought state expertise in determining jurisdictional lines between transmission and distribution facilities, and stated that it would defer to state recommendations in this regard. For this purpose, FERC has articulated seven indicators of local distribution to be evaluated on a case-by-case basis:

[33]During the proceeding, it was suggested that the FERC-established rates might be considered CMP's marginal transmission cost and become part of the EPMC reconciliation. CMP and the IECG opposed this concept. If the FERC defers to our costing methodologies, the actual societal marginal cost of transmission should be calculated, rather than assuming that the FERC rates are the marginal costs. Otherwise, FERC's embedded methodology should be used as part of a hybrid methodology as proposed by CMP and the IECG.

[34]CMP suggested we open a generic rulemaking on transmission issues. We believe an investigation would be more appropriate procedural vehicle.

(1) Local distribution facilities are normally in close proximity to retail customers.

(2) Local distribution facilities are primarily radial in character.

(3) Power flows into local distribution systems; it rarely, if ever, flows out.

(4) When power enters a local distribution system, it is not reconsigned or transported on to some other market.

(5) Power entering a local distribution system is consumed in a comparatively restricted geographical area.

(6) Meters are based at the transmission/local distribution interface to measure flows into the local distribution system.

(7) Local distribution systems will be of reduced voltage.

Id. at 230.

FERC requires utilities to consult with their state regulatory authority "as a prerequisite to filing transmission/local distribution facility classifications and/or cost allocations with the Commission," and encourages public utilities and their state commissions to attempt to reach agreement in these areas. *Id.* at 251. FERC indicated that if the "utility's classifications and/or cost allocations are supported by the state regulatory authorities and are consistent with the principles established in the Final Rule, the Commission will defer to such classifications and/or allocations."[35] *Id.*

Because of our desire to work cooperatively with FERC, a primary purpose of this investigation is to consider the proper split between state and federal jurisdictional facilities, along with appropriate cost allocations. The desired end result

[35] FERC indicated that the states should specifically evaluate the seven indicators, but noted that there could be other relevant factors. *Id.* at 251 n.548.

would be utility filings at FERC that the Commission could support. These filings could also be a vehicle for utilities to present for FERC approval its transmission revenue requirement, as well as retail rates, terms and conditions.

As part of a generic transmission proceeding, CMP suggests that the following issues be explored:

> - Whether customers should have the opportunity to purchase transmission services pursuant to the appropriate open access transmission tariff (OATT), or whether transmission services should only be included with local distribution services in retail T&D rates.
>
> - Whether load-serving entities that provide electric energy to Maine customers can include transmission services with their generation services; in other words, can load-serving entities purchase transmission services on behalf of their customers, with the result being that the T&D utility would not charge these customers for transmission services;
>
> - Whether transmission providers will be hurt if customers or load serving entities can choose to take transmission services under the appropriate OATT and, if so, whether the Commission should permit Maine utilities to reconcile FERC-approved transmission revenue requirements with actual recoveries so transmission providers are not hurt by the selections; and
>
> - Development of a process for filing the rates, terms and conditions of unbundled retail transmission service with FERC.

We agree with CMP that these types of issues should be explored and we will include them in our investigation.

E. Stranded Cost Allocations

1. Positions Before the Commission

Several approaches to allocating stranded costs among customer classes were proposed in this proceeding.

CMP states that under its top-down approach, stranded costs are recovered in the same manner as in the past. Over the long term, CMP proposes allocating stranded costs among customer classes based on relative class revenue contributions at the Company's existing rate caps. Under this approach, if a class (during a test year) contributes 40% of the Company's revenue at the capped rates, then 40% of stranded costs would be allocated to that class. CMP views this approach as equitable in that it tempers revenue realignments and strives to preserve the current rationale for cost allocation. CMP states that at the time stranded costs were being incurred, the Commission was making decisions regarding allocations, and those past decisions should form the basis of stranded cost allocations in the future.

The Public Advocate proposes that stranded costs should be allocated on energy usage, because the costs were incurred primarily to serve energy requirements. The Public Advocate supports its position by noting that stranded costs are primarily associated with baseload resources (e.g., QF contracts, nuclear plants) and that no peaking plants are included in stranded costs. The Public Advocate opposes the Company's current rate cap approach, because, over time, it could produce stranded cost allocations based in part on T&D costs.

The IECG proposes that stranded costs be allocated 50% on energy and 50% on demand. The IECG's view is that stranded costs were incurred to meet both energy and capacity needs and that a 50-50 split is a fair balancing for allocation purposes, because it is not possible to resurrect the relative needs for energy and capacity in the past or the resulting investments that currently constitute CMP's stranded costs. The IECG proposes the use of the NEPOOL formula to allocate the capacity portion because this reflects the manner in which NEPOOL assigned capacity responsibility during periods when most of the stranded costs were incurred.[36] For energy, the IECG proposes using relative class energy consumption.

The Bench Analysis also offered an alternative allocation of stranded costs based on a combination of energy and demand .[37] This approach (like that of the IECG) recognizes that stranded costs are generation-related and thus have an energy and capacity component. To explore a basis for determining the relative weighting of energy and capacity with respect to how the costs were incurred, the Bench Analysis contained a review of recent CMP marginal costs studies and its projection for market prices in the year 2000. This review showed an energy/capacity ratio ranging from 80/20 to 70/30. Based on this analysis, the Bench Analysis concluded that it would be reasonable to allocate stranded costs 75% on energy usage and 25% on demand.

The Bench Analysis also noted that nuclear decommissioning costs present a unique category of costs. Although they are costs of the T&D utility, they are clearly generation-related. As such, the Bench Analysis suggests that these costs should be allocated in the same manner as stranded costs.

[36]The NEPOOL formula weighted annual system peak and the average of 12 monthly peaks by 70% and 30% respectively.

[37]The Bench Analysis noted a further alternative in which stranded costs are allocated based on stranded cost levels implied by the difference between current rate caps and the newly-established T&D class allocations, but concluded that such an approach would simply offset the effect of any T&D revenue reallocation.

2. Analysis and Conclusion

We conclude that an allocation of stranded costs on both energy and demand is the superior approach, and that an allocation of 75% of the costs on energy and 25% on demand represents a reasonable weighing of these generation components.

Stranded costs are sunk generation-related costs. Because the costs are sunk and not ongoing, equity concerns should drive the allocation.[38] CMP's approach attempts an equitable allocation by reference to current rate cap revenue. However, the current rate caps are a result of a marginal cost based allocation with an EPMC reconciliation to CMP's total revenue requirements. The allocation also reflects substantial rate stability smoothing and several subsequent across the board allocations of rate increases. For this reason, it is difficult to place too much weight on the notion that current rate cap revenues represent prior Commission allocation of CMP's stranded costs. Nor can it be viewed as preserving any cost allocation rationale that was in place at time stranded costs were incurred, since stranded costs were incurred in the past over several decades. Additionally, CMP's approach has the consequence of allocating generation-related costs based on factors having nothing to do with the cause of those costs (e.g., relative customer and distribution costs).

[38]CMP agrees with this view; but notes that, if efficiency is the focus, inverse-elasticity principles could be applied. CMP does not recommend using such an approach as allocating based on relative class elasticities would be controversial. It states that elasticities are better accounted for through more targeted pricing flexibility efforts. We do not disagree with CMP in this regard, but would add that reflecting inverse-elasticity principles in the design of rate elements may also be an option; this is preferred to allocating class revenue responsibility on this basis, which requires gross generalization about customer class elasticities, and is a less direct way to affect usage.

From an equity perspective, costs should be allocated upon some relationship to their causation. Because stranded cost are generation-related, it is appropriate to allocate them on the basis of a mix of energy and capacity consistent with the requirements of CMP's system. We disagree with the Public Advocate that costs should be allocated entirely on energy. Although most of CMP's stranded costs are associated with resources that could be characterized as baseload, these resources contain a capacity component. Moreover, what we are allocating are CMP's net stranded costs which reflect the total of CMP's generating resources; accordingly, the relative amounts of capacity and energy in these costs are best measured by CMP's system requirements over time. We also disagree with the IECG proposed 50-50 split, which is based on an assumption that there is no reasonable basis to determine an appropriate split. Our view is that an examination of CMP's prior marginal cost studies and market price projections as contained in the Bench Analysis provides a sufficient basis for weighing the components without having to rely on an arbitrary 50-50 split. It is also consistent with the "peaker methodology" that we adopted in the past for purposes of allocating generation costs; this methodology assumes the capacity component of generation to be the least-cost means to meet peak demand. *See* Docket No. 89-068 Order at 29-34. Accordingly, we adopt the Bench analysis proposal of a 75%/25% weighing of energy and capacity. The allocation method for each component should be as proposed by the IECG: energy based on relative class energy consumption, and capacity using the prior NEPOOL 70/30 weighted annual and monthly peaks formula.

We also agree with the Bench Analysis suggestion that nuclear decommissioning costs should be allocated in the same manner as stranded costs. CMP agreed with this suggestion and no party opposed it. Decommissioning costs are clearly generation-related and are part of the transition to an unregulated generation market. As such, it is appropriate to allocate decommissioning costs in the same manner as stranded costs.[39]

F. Future Use of Cost Studies

In a major discussion of rate design over 10 years ago, we found that electric rate design would primarily be based on marginal costs employing an equi-portional approach (EPMC) for class allocations. Docket No. 89-068 Order. We did, however, require the continued filing of embedded cost studies, at least on an interim basis, as a secondary set of information. *Id.* at 23, 50-51. Embedded studies have had little influence in recent cases. *See* Docket No. 95-052 Order. For the reasons discussed below, however, we will require future utility rate design filings to include both marginal and embedded cost studies, and leave for those cases decision as to their relative use in rate re-designs.

1. Positions Before the Commission

[39]CMP also proposed that DSM expenses be characterizes as stranded costs for allocation purposes. As discussed in Part 2, DSM costs incurred prior to March, 2000 are generation-related stranded costs. Accordingly, we have determined that the available value from the asset sale should be used to offset prior DSM costs. To the extent such costs are not offset by the available value from the asset sale (e.g., amounts that will be paid for in the future), they should be allocated as stranded costs. New conservation costs under 35-A M.R.S.A. § 3211, however, are not generation-related, but are social costs analogous to low income program costs. These will be allocated as part of CMP's non-stranded cost revenue requirement.

All of the parties appear to agree that, if reliably estimated, marginal costs provide a superior basis for the determination of economically efficient prices. The Public Advocate, however, argues that embedded cost allocations are superior in achieving the equity objective because, in part, they match class revenues to cost responsibilities. In the Public Advocate's view, no such matching is provided by the use of marginal costs and an EPMC reconciliation; for example, use of the Company’s marginal cost study systematically shifts responsibility for costs to the residential class by arbitrarily inflating the customer related share of revenue requirement.

The Public Advocate also argues that there is no generally accepted methodology for measuring marginal T&D costs. The Company does not have a complete and systematic set of marginal cost estimates; transmission costs are allocated using FERC's embedded costs, and distribution O&M and customer-related expenses are essentially average embedded costs. Consequently, CMP and the IECG essentially propose to use a combination of average embedded and marginal costs to arrive at a set of class revenues that will equal the total jurisdictional revenue requirement.

CMP and the IECG argue for the continued reliance on marginal costs and EPMC as the basic approach to class allocations on the grounds that this methodology best promotes the economic efficiency of rate design. CMP also suggests that the ERRA may require this approach in that it refers to rates that reflect marginal costs. 35-A M.R.S.A. § 3153-A(1)(B). CMP responds to the Public Advocate's concerns by stating that, just because a price signal is not perfect, we should not abandon the goal of efficient pricing. Finally, CMP argues that there are no particular advantages to an embedded costs approach, and its use would lead to substantial new controversies over what are inevitably arbitrary allocations.

2. Analysis and Conclusion

Our review of the record and the arguments of the parties in this case causes us to re-evaluate our primary reliance on marginal costs in establishing class allocations for T&D utilities. It does not appear that a methodology for reliably measuring marginal distribution costs has been developed. Additionally, it is difficult to assess whether our traditional marginal cost/EPMC methodology can serve the purposes for which it was originally adopted at least through a transition where stranded costs are major component of revenue requirements. The EPMC methodology was originally adopted as the best means to promote economic efficiency and create proper price signals; the approach was also considered equitable in that each customer would pay the going-forward cost of providing service plus a proportionate share of the reconciliation amount. However, it is difficult to determine if these purposes can be achieved through the use of the type of hybrid methodologies proposed in this case. As discussed above, these hybrid methodologies generally involve use of marginal customer and distribution costs, reconciled to a distribution revenue requirement; with an embedded based transmission cost allocation; and an equitable stranded cost allocation based on historic cost causation. Moreover, any time there is a large reconciliation between total marginal costs and total revenue requirement, a question arises as to effectiveness in promoting economic efficiency and the equity of the resulting allocation.[40]

Embedded costs, like marginal costs represent a cost basis for designing rates. They differ in that embedded costs are historic, rather than the forward-looking costs. Embedded cost allocations are based on "cost-causation" principles and are thus premised on equity considerations rather than the promotion of efficiency. Specific embedded cost allocations are often controversial because there may be numerous reasonable allocation approaches (primarily with joint and common costs) that can significantly impact the results,[41] as such, it is often difficult to determine which allocators to adopt.

We recognize the deficiencies with embedded studies; however, they can provide a measure of equity consistent with our rate design principles. Moreover, we should not abandon the examination of embedded cost allocations until we have more confidence that marginal distribution costs can be reliably measured for purposes of rate design. Although efficiency will remain a primary objective in designing rates, we will require the filing of an embedded study along with a marginal cost study in future rate design proceedings.[42]

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[40]In our most recent electric rate design proceeding, we expressed concern about the use of the EPMC methodology in light of a large reconciliation amount, questioning the validity of the resulting price signals and the equity of the resulting allocations. Although we did not abandon the approach, we indicated that it would represent only a starting point for pricing decisions. Docket No. 95-052 Order at 37-40, 43.

[41]It is for this reason, that the Commission has indicated that embedded cost allocations tend to be "arbitrary." Docket No. 95-052 Order at 38; Docket No. 89-068 Order at 26.

[42]We disagree with CMP that the ERRA requires class allocations based on

marginal cost. The cited section refers only to rates that "reflect" marginal costs at different voltage levels and times-of-use, which is a rate design directive that we intend to follow. We do agree with CMP, however, that efficiency can be pursued through intraclass rate design and flexible pricing.

IV. STANDBY RATES

The restructuring Act directs the Commission to establish standby rates as part of this proceeding. 35-A M.R.S.A. § 3209(2). This topic has been one of the most contentious issues in the proceeding. Among the most controversial aspects of the design of standby rates are whether it is appropriate to impose charges based on contract demand; whether the diversity of standby customers' loads should be taken into account when determining their responsibility for T&D costs; and recovery of stranded costs from standby customers consistent with the Act's prohibition on exit fees, 35-A M.R.S.A. § 3209(3). We address each of these issues in detail. We also describe the basic structure for standby and station service rates and determine how these rates should be designed in Phase II of this proceeding.

A. Self-Generation and Stand-Alone Generators

CMP modified its initial standby rate proposal to an adaptation of the proposal offered by Mr. Chernick on behalf of the Public Advocate. The Company's proposal is contained in the August 31, 1998 surrebuttal testimony of witnesses Dumais, Peaco and Parmesano. CMP's proposal reflects different treatments for self-generators (electricity end-users that provide some of their own electricity) and stand-alone generators (facilities engaged solely in generating and selling electricity). Under CMP's proposal, self-generators with standby loads of 400 kW and over would take service under the standby rate. Stand-alone generators with loads of 400 kW and over would take service under the applicable core rate, as they do now, but with the demand ratchet retained. The service provided to stand-alone generators is called station service. All customers with standby or station service loads of less than 400 kW would also continue to pay for their service under core rates, which CMP proposes would no longer have demand ratchets.

In theory, there should be no difference between the costs incurred to serve the standby loads of large stand-alone generators and those incurred to serve large self-generators. If we were prepared to make an immediate, one-step move to fully cost-based rates, there would be no apparent justification for treating these two types of customers differently. However, CMP has proposed, as a general objective, that March 1, 2000 rate be designed to minimize adverse bill impacts to its customers. In keeping with that objective, CMP proposes to treat station service customers on a similar basis as they have been treated in the past to avoid adverse bill impacts. In contrast, because the standby rate will largely apply to new self-generators, bill impacts are a lesser concern.

As discussed above, we agree that minimizing bill impacts should be the primary near term rate design objective. Accordingly, we conclude that CMP's proposed distinction is reasonable for rate stability purposes; in the future, the Company should move towards serving all standby customers under the standby rate as rate design changes are implemented over the longer term.

B. Standby Rates for Self-Generation

1. Small Standby Customers

CMP's argues that requiring small customers with standby loads to take service under a separate standby rate would not be cost effective because of high transaction costs[43] and the relatively small impact that these customers have on

[43] CMP did not explain the exact nature of these transaction costs.

distribution planning compared to large standby customers. These witnesses therefore proposed that small customers continue to take standby service under standard core rates. The Company proposes 400 kW as the dividing line between small and large customers.

CMP's filing indicates that there are numerous customers between 100 kW and 400 kW that the Company believes to have self-generation capability. To the extent CMP has proposed the 400 kW breakpoint because of the difficulty involved in identifying smaller self-generators, it appears that many of these customers have already been identified. Additionally, the fact that customers of this size have a smaller impact on distribution planning than large customers has little to do with the question of whether to charge them a standby rate. As discussed below, the impact of customer size on CMP's distribution planning and, thus, distribution cost responsibility does not depend on whether a customer takes standby or full requirements service. Moreover, a standby rate is appropriate for self-generators of any size, because the structure of the rate allows for the proper amount of cost recovery from such customers.

The question, then, is whether there is a reasonable basis to exempt small customers from the standby rate and charge them, instead, as a full requirements customer under a rate design that does not contain a ratchet. We do not believe such a basis exists. CMP should therefore charge all customers with standby demands of 100 kW and above under the standby rate set in this proceeding.[44]

2. Contract Demand Charge

[44]There does not appear to be significant potential for self-generation for customers below 100 kW.

Under the Company's proposed standby rate, contract demand charges would be used to recover transmission, distribution and stranded costs. In other words, a customer would be charged based on the amount of contracted for demand, rather than on the amount actually used. The Company proposes that separate peak and off-peak contract demands be established, with incremental off-peak demand charged at a lower rate to reflect the diurnal variation in distribution costs. This provides an incentive to use the service during off-peak hours. We find this feature to be a proper component of the standby rate.

As we discuss more fully below, the use of a contract demand for billing purposes makes sense for standby customers, as long as the unit charges to recover the allowed revenue requirement are developed on the basis of contract billing demands. Contract demand is a reasonable billing basis for standby customers given the uncertainty of their actual demands and because standby service, by its very nature, is a reservation service. The customer is purchasing a reservation of capacity to serve its contract demand whenever required. Billing on a contract demand basis better matches the billing method with the costs that are incurred to provide the standby customer with service.

3. Distinction Between Diversity and Reservation

Much of the debate in this proceeding regarding standby service has focused on whether diversity should be taken into account when determining the costs that a standby customer imposes on the system, and whether that customer should be charged on the basis of a contract demand as opposed to an "as-used" basis. Some of the arguments suggest that parties believe these issues are one and the same; either diversity is accounted for, or a customer should be charged on a reservation basis -- i.e., using contract demand. These are, however, two distinct issues that must be addressed separately. Diversity relates to costing, while reservation relates to rate design or billing basis.[45]

Whether to recognize customer diversity is a costing question. What loads of a customer are relevant to system design, expansion and costs? Does a customer add to the costs of the system based on its maximum demand whenever it occurs, or on the basis of its demand at the time of the relevant system peak? The system at issue could be the regional or local transmission system, or a circuit on the distribution system. For transmission, CMP asserts that cost allocation is FERC-jurisdictional and proposes to charge standby customers its FERC-approved transmission rate based on the customer's contract demand. With regard to local distribution system costs, the Company maintains that it adds capacity on a kW for kW basis to meet the maximum potential load of large customers (400 kW and above) in addition to the coincident peak loads of all small customers on the system. As a result, CMP states that diversity is not recognized when planning the distribution circuit that contains the load of a large customers.

Although parties have questioned the efficiency of CMP's expressed planning criterion, given this criterion, distribution costs should be ascribed to large customers based on their maximum potential demand. For standby customers, this is their contract demand. If, on the other hand, the diversity of these customers’

[45]A failure to distinguish between these two issues can complicate consideration of whether a reservation charge which includes stranded cost recovery is comparable to an exit fee. This issue is discussed in section IV(5) below.

loads were recognized, distribution costs could be ascribed using their actual contributions to the relevant peak, or contract demand could be multiplied by the customer's coincidence factor to obtain the cost responsibility recognizing diversity. The use of one approach as opposed to the other provides a different estimate of cost responsibility, one that recognizes diversity and the other does not.

The rate design or billing question goes to the most appropriate way to recover those costs, once estimated. Assuming it is appropriate to recover the costs in demand charges, rates can be designed to recover the costs using contract demand charges, or using actual demand with or without a ratchet, assuming there exists a reasonable estimate of the billing determinants for actual use. The same costs can be recovered from the customer under any of these rate design/billing approaches, and the costs recovered can either reflect or not reflect the diversity of the customer's load; as such, a contract demand charge can be set to recover costs that either recognize or do not recognize diversity. Alternatively, an "as-used" demand charge theoretically can be set to recover costs that either reflect or do not reflect diversity.

We discuss below whether diversity should be reflected in ascribing CMP's T&D costs to standby customers. As for the question of rate design, as noted above, standby service is a reservation service. The utility agrees to stand ready to meet the customer's load whenever it occurs, unless the contract limits the times when the utility is obligated to serve. If the customer's actual load over the year could be predicted with some degree of certainty, then an "as-used" rate could be designed to recover the costs appropriately ascribed to standby customers. But, in fact, the standby customer's actual load is uncertain, so it is difficult, at best, to design an “as-used” rate that would recover the right revenue. Using a contract demand charge permits the proper revenue to be recovered because the billing determinants are certain and is, thus, the most appropriate way to design a standby rate.

4. Recognition of Diversity

In this section, we address whether to reflect diversity in determining standby customer responsibility for transmission and distribution costs. Diversity is defined as the ratio of a customer’s (or a class’) highest demand (whenever it occurs) to that customer’s (or class’) demand at the time coincident with the peak on the relevant system. The relevant system could be generation level, some portion of the transmission system, or a local distribution circuit. Savings from diversity result when the utility can build its system to meet the coincident loads of its customers rather than the much higher sum of individual customer maximum demands. These savings, or diversity benefits, are generally distributed among customers in proportion to their contributions to system diversity. This is accomplished by allocating system costs in proportion to coincident demands. The parties agree that diversity is greatest at the generation and bulk transmission level, and declines as one moves from the generator to the meter. For example, for a facility dedicated to a single customer (e.g., meter) there is no load diversity. However, as long as equipment serves at least two customers there will be some load diversity on that equipment, unless the two customers have identical load patterns. The issue, then, becomes a quantitative question of how much diversity exists and how (or if) it affects the planning and construction of the system.

In this proceeding there has been much testimony and argument regarding the diversity of standby customers' loads and the cost and revenue responsibility consequences of this diversity. That the loads of standby customers are more diverse than full requirements customers is not in dispute. What is in dispute, however, are the cost and revenue implications of that diversity.

a. Transmission

There seems to be little disagreement that diversity benefits exist at the transmission level and that CMP takes these benefits into account when it decides how much transmission capacity it requires. However, CMP argues that FERC has jurisdiction over retail transmission rates and that FERC Order No. 888 requires that behind-the-meter generation be included in calculating the transmission charge. For a standby customer, the Company argues, this means that transmission cost responsibility should be set on the basis of the customer's maximum potential demand (i.e., contract demand) rather than its actual contribution to the monthly coincident peaks, which, CMP asserts, FERC would require for requirements customers. In other words, the Company argues that the diversity of standby customers cannot be considered in determining their cost responsibility for transmission. FPL Energy Maine, Inc., the Independent Energy Producers of Maine and S.D. Warren Company (the Generators) and the IECG, on the other hand, have each taken issue with CMP's interpretation of FERC's "behind-the-meter" ruling, arguing that it is not applicable to the determination of transmission cost responsibility for retail customers.

Although the "behind-the-meter" debate has received much attention in this case, it does not appear particularly relevant, even to CMP's proposed standby rate. Although CMP asserts that FERC rules require a customer to pay for transmission based on the size of the customer's own generation, CMP is not actually proposing to charge any standby or station service customer in this way. Rather, CMP has proposed to charge for transmission based on contract demand in the case of a standby service and ratcheted demand in the case of station service. For both, transmission cost responsibility would reflect some diversity benefits, those of the full requirements class,[46] but not the additional benefits CMP acknowledges it would realize in terms of savings on its transmission system from the much greater diversity of standby customers' load.

The "behind-the-meter" issue has even less relevance to the top-down, bundled T&D standby rate that we describe in section IV(D) below, and which we adopt in this proceeding. This standby rate does not involve any direct allocation of transmission costs to standby customers nor a separately charged rate component for transmission. Moreover, as discussed in section III(D), we would seek allowance from FERC if necessary to allocate and design the transmission portion of CMP's bundled T&D rates, consistent with underlying costs and other rate-setting objectives.

b. Distribution

The diversity issue is different with respect to distribution costs. The Company has stated that it plans for distribution capacity to meet the loads

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[46]Our interpretation of the Company's standby rate as derived in the Dumais, Peaco, Parmesano Surrebuttal at Ex. DPP-46 is that the FERC transmission rate charged to standby customers on the basis of contract demand is effectively scaled down to reflect the transmission cost responsibility of the corresponding core class, which is set using the core class' coincident demand.

of large customers (400 kW and above) on the basis of their maximum potential loads, not on the basis of their coincident loads. Thus, CMP argues that it is inappropriate to account for the diversity of standby customers' loads when determining their responsibility for distribution costs. The IECG, the Generators and RWS all disagree. They provide arguments for and empirical evidence that shows that standby customers contribute little to the coincident system peaks. They then argue that the Company either actually does or should account for this diversity when allocating distribution costs to standby customers.

There appears to be little doubt that standby customers contribute little to the Company's peaks on a probabilistic basis. This case was made convincingly by the IECG, the Generators, and RWS. The evidence seems to indicate that the relevant coincident factors are between 5 percent and 25 percent for standby customers.

However, CMP asserts that the coincidence factors of standby customers are irrelevant. CMP claims that due to the size of a standby customer (which CMP proposes as 400 kW and above) it would size the distribution circuit to meet the customer's maximum potential load. Specifically, CMP describes its planning criterion as the coincident loads of small customers plus the maximum potential load of large customers. James Begin, CMP's Manager of Transmission and Distribution Planning, represents that the size and unpredictability of these large standby loads require that CMP size circuits on a kW-for-kW basis to be prepared to meet these customers' maximum loads whenever they occur, including at the time when other customers' coincident loads are highest. Mr. Begin further stated that on

CMP's system there is generally only one large customer on a circuit together with a number of much smaller customers and, as a result, the large customer would dominate the load on the circuit.

The intervenors' responses to Mr. Begin's testimony range from disbelief to criticism, and, in some cases reflect both. We understand this response. The notion that utility systems are planned to meet the relevant coincident loads of customers is the conventional wisdom, and results in one of the primary rate design challenges -- how to allocate those diversity benefits among classes of customers. Moreover, in all past CMP cost allocation studies we have reviewed, distribution costs have been allocated reflecting the diversity of CMP's customers both small and large. However, it is understandable that CMP would not account for the diversity of large customers when there is a single large customer on a circuit with a number of smaller customers. In such a case, a large customer's requirements could overwhelm the requirements of other customers.

Notwithstanding conventional wisdom, CMP is correct in noting that its witness, Mr. Begin, was the only engineer to testify on this point and that no other system planner, or expert on planning, testified in this case. Accordingly, we accept Mr. Begin's description of how the distribution system is planned and the resulting causation of capital costs.[47] As a general matter, costs should be assigned to reflect the way in which the system is actually planned and costs are incurred. Because the Company sizes its distribution plant to meet the maximum potential load

[47]The parties responses to CMP on this point indicate that they question the prudency of the Company's distribution planning criterion. However, no party has presented evidence or proposed a remedy for any imprudence in this regard.

(e.g., contract demand) of large standby customers, then costs should be assigned to these customers accordingly.

5. Stranded Cost Recovery

Under CMP's proposal, the recovery of stranded costs from standby customers is based on the costs that are assigned to full requirements customers on the core rate corresponding to the standby customer's load and voltage level of service. More specifically, the Company determines the total stranded costs to be recovered from customers served under the core rate and divides that amount by a measure of usage equivalent to the total contract demands of those customers. As a proxy for contract demand, CMP uses the sum of the annual maximum measured demands of the customers on that rate schedule. The resulting kW charge is the rate that would apply to customers on that core rate if the class' stranded costs were to be recovered from core customers on the basis of a contract demand charge. This kW charge is then applied to the standby customer's contract demand to determine its stranded cost obligation. The result of CMP's approach is that a standby customer would pay an amount of stranded costs that is comparable to a full requirements customer with the same demand and voltage level of service.

The primary objection parties have raised regarding this aspect of CMP's proposal is that it would constitute an exit fee which is proscribed by the Act. We find that CMP's basic approach does not constitute an exit fee under the Act, that an approach that recovers a similar amount of stranded costs from standby customers as comparable requirements customers is appropriate, and that such an approach should accordingly be incorporated in the design of standby rates.

Some parties suggest that use of a contract demand charge for stranded cost recovery is an exit fee. In preceding sections, we discussed why recovering costs through a contract demand charge would not be unreasonable or treat standby customers unfairly. Different billing methods are frequently used to recover the same costs from different groups of customers. The most obvious example is the recovery of demand costs from some customers through demand charges, and recovery of these same demand costs from other customers through energy charges. The test for reasonableness when comparing two billing methods is whether they would recover essentially the same revenues if the billing information were available to permit either method to be used. CMP has developed the stranded cost charge for standby service by simulating recovery of full requirements stranded costs as if done on a contract demand basis. All of CMP's stranded costs could be recovered this way. CMP does not propose to do so because requirements customers' actual use is fairly predictable, and so as-used billing can be relied upon to recover the proper revenue. As noted above, that is not the case with standby customers, and so a contract demand billing method is relied upon under which a standby customer will pay the same stranded costs as would a requirements customer in the same class if the requirements rates were designed and charged using contract demands. Thus, the use of a contract demand charge does not, per se, constitute an exit fee, as suggested by some parties.

The real question, then, is whether a standby customer with a contract demand of a particular amount, e.g., 1 MW, should pay the same amount of stranded costs as a requirements customer with 1 MW of actual demand. In our view, they should pay the same amount. As a general proposition, stranded cost responsibility should relate to the level of service a customer takes from the utility. In the case of the requirements customer, measuring that service is straightforward. In the case of standby service, the utility service provided may involve concepts less-familiar to traditional rate design, but no less straightforward.

As noted earlier, standby service is a reservation service. When a customer enters into a standby service agreement with the utility, it receives a commitment from the utility that it will stand ready to meet whatever demand the customer chooses to contract for. The utility provides this service by reserving sufficient capacity to meet the customer's contract demand. It is reasonable to consider the level of service provided as measured by the amount of demand that the contracting parties agree the utility will stand ready to serve. A standby customer with a 1 MW contract demand will receive 1 MW worth of T&D service from CMP, just as a requirements customer does with a 1 MW maximum actual demand. Because the service levels are comparable, it is proper for each customer to make the same contribution to recover the stranded costs of the system.

We, therefore, find it is reasonable to recover stranded costs in standby rates this way. However, we must determine whether doing so amounts to an exit fee as that term is used in the Act. We conclude that this approach does not constitute an exit fee within the language of the Act.

The operative language in section 3209(3) states:

> A customer who significantly reduces or eliminates consumption of electricity due to self-generation . . . may not be assessed an exit or reentry fee in any form for the reduction or elimination of consumption or reestablishment of service with a transmission and distribution utility.

A T&D utility provides only delivery service to its customers. A standby customer with a 1 MW contract demand reserves delivery capacity on CMP's system of 1 MW. If that standby customer had previously been a requirements customer with a 1 MW actual demand, then there has been no reduction in the consumption of service obtained from the transmission and distribution utility. In this instance, the same level of delivery service is being used and to require the same stranded cost contribution does not constitute an exit fee.

On the other hand, a standby customer that was previously a 1 MW requirements customer may contract for only 500 kW of standby service. In this instance, there would be a reduction in consumption of T&D service and the customer would pay for stranded costs (and all other charges) based on the 500 kW level of service. In this way, the stranded cost contribution for all customers will be proportional to the amount of T&D service they receive and, thus, in compliance with § 3209(3). In our view, this approach provides a fair, reasonable and legal allocation of stranded cost responsibility among CMP's customers.

C. <u>Station Service Rates for Stand-Alone Generators</u>

As noted previously, we adopt CMP proposal to charge stand-alone generators for station service under the core tariff that would apply based on the customer's load and voltage level of service. This charge for station service will be based on ratcheted demands, whereas the demands of full requirements customers would not be subject to a ratchet. We discuss three issues that arise from CMP's proposal below.

1. <u>Stand-Alone vs. Net Generators</u>

Under CMP's approach, station service would be available only to stand-alone generating plants. All other customers would take standby service to back up their generation. The Generators argue that customers whose generation on net exceeds their load should be placed into the station service category because net generators (like stand-alone generators) paid for the T&D facilities to accommodate their generation.

As discussed below, the Generators' argument that they should not pay for any T&D costs associated with providing them service is not persuasive. Because we believe that the dividing line proposed by CMP between station service and standby service customers is less ambiguous than that proposed by the Generators (e.g., is a 1 MW net amount of generation enough? a 1 kW?) and because there are no cost-based reasons to treat net generators differently than other self generators, we will adopt CMP's approach. We also find persuasive CMP's argument that rate stability considerations would support the same division.

2. Incremental T&D Costs to Provide Station Service

The Generators argue that net generators paid for any T&D facilities that CMP was required to install to accommodate the net generator’s output. Moreover, the Generators argue that net generators, or their customers, also pay ongoing wheeling charges to CMP for the cost of maintaining a T&D system capable of delivering the net generator’s output out to its load. Consequently, the Generators argue that there is no incremental cost to provide standby T&D service to net generators. Therefore, an appropriate rate to net generators would be limited to a per customer allocation of customer accounts expenses and customer service and information expenses, marked up by an appropriate EPMC factor (the same as for all other classes) to recover from these customers their “fair share” of stranded costs and other sunk costs.

The Company takes issue with the Generators' assertion that the generator pay for all of the upgrades necessary to deliver its output to the grid. It states that generators only paid for immediate, incremental cost needs; if excess capacity existed when a generator connected to the system, the generator was not required to pay CMP for upgrades to the system. In summary, the Company states that:

> Generators did typically pay the costs of hooking their equipment to CMP’s system. They did not make upfront payments for the entire system they use, e.g., the generator in many instances did not contribute to the cost of the distribution substation for that customer’s circuit. Nor do they pay anything for the upstream costs incurred in serving them.

But the major thrust of the Company’s argument seems to be that, regardless of what connection costs were borne by the generator, such payments do not absolve the customer from any future, on-going charges to remain connected and obtain the provided benefits.

The critical aspect of the cost responsibility of stand alone generators has less to do with the initial upgrades that were required and the up-front payments that were made at the time of the connection, and more to do with the long-term contribution to continuing T&D costs as the T&D system is continually upgraded and expanded to meet the growing needs of all of CMP’s customers, including the stand-alone generators. The more persuasive argument appears to be that generators, or their customers, will continue to pay the T&D delivery charges (as appropriate) for all of the power that is sold by these generators. As a result, there is a contribution to the ongoing cost of the T&D system, including the cost of all necessary future upgrades, just as with all other customers who use the CMP T&D system.

However, this fact does not mean that the generators should pay nothing for their use of the T&D system when they purchase station service. These intervenors do not raise the question of whether it is appropriate for their customers to pay the T&D delivery costs associated with their energy, and it is similarly reasonable that station service customers, as retail customers, bear their proportionate share of the costs of the T&D system when it is used to deliver energy to them. There is no difference between an end-use customer using the energy produced by a generator to illuminate the lights in a house or a factory, and the generator, purchasing electricity from some other producer to illuminate the lights in his generating plant when the plant is not operating. Both are end-use retail customers, and both should pay the tariffed rate for T&D service. As CMP argued in its Reply Brief (p. 73):

> CMP does not identify which specific customers are imposing incremental costs on the system in designing rates . . . Instead, the challenge to rate designers is to identify cost drivers and to use those drivers to develop generally applicable rates to recover the Company's revenue requirement.

It is important to keep in mind that CMP will not recover any additional revenues by charging these stand-alone generators for the use of the T&D system. It is, rather, a question of cost allocation. The Company will recover its allowed T&D revenue requirement. The issue is who will pay the Company's costs. If station service customers do not pay when they use CMP's system to obtain energy, other customers will make up the difference.

3. Stranded Costs

FPL Energy Maine, Inc. (FPL) raises a separate issue with respect to stranded costs in station service rates. FPL argues that, because under NEPOOL rules the station service loads of CMP-owned generating plants never contributed to CMP's capacity requirements, CMP incurred no generation-related stranded costs to provide them service. Thereby, FPL argues, it should not be charged any stranded costs associated with the station service requirements of those generating plants. CMP's response to this argument is that the total charge to FPL under its proposed standby rate is reasonable. CMP also notes that it does not trace stranded costs to customers, which is the implication of FPL's position.

FPL has accurately described NEPOOL's treatment of the station service loads of CMP-owned generation plants. As noted by FPL, NEPOOL rules allowed utilities to deduct their own station service from their monthly peak loads for the purpose of calculating capability responsibility. However, FPL's argument overlooks the fact that CMP's planning criteria for generation involved consideration of energy as well as capacity. Even if the station service loads of CMP-owned generating plants did not contribute to its capacity requirements, there is no evidence that these loads did not contribute to energy requirements. Moreover, we agree with CMP that stranded cost responsibility should not be tagged so specifically to particular customers based on historic conditions. To do so could lead to outcomes, for instance, whereby new customers would pay no stranded costs. There may be a rationale for such an outcome based on the fact that new customers did not cause CMP to incur any stranded costs. However, we decline to adopt a system with different rates for "new" and "old" customers; all customers should be charged comparably based on their current use of CMP's system.

4. Retaining the Ratcheted Demand Charges

The Company has proposed to eliminate the demand ratchet for full requirements customers. However, the Company proposes that station service customers take service off of the full requirements rate schedules, but with the ratchet retained. In and of itself, we do not find the use of a ratchet inappropriate for station service customers because of the uncertainty of their actual use, and the resulting difficulty of designing an “as-used” rate that will recover the proper revenues. However, we do have concerns regarding the Company’s proposed retention of the ratchet as we understand it.

CMP is proposing to eliminate the demand ratchet for full requirements service. This effectively lowers the billing units of the class. The Company must then apply a higher unit demand charge to the unratcheted billing demands in order to recover the same revenue. It is internally inconsistent to then use these same demand charges to recover revenues from station service customers using ratcheted demands. That would lead to an overrecovery of these costs from station service customers. It will be necessary to calculate a separate, ratcheted demand charge for these customers. This is properly done by dividing the demand-related costs allocated to each rate class by the estimated ratcheted billing demands for all customers in the class, including the station service customers. Unless that is done, retaining a demand ratchet for station service customers taking service off the appropriate standard tariff, but with the ratchet retained, will treat such customers unfairly and recover excess demand costs.

D. Specific Design for Station Service and Standby Rates

As stated above, there are several aspects of CMP's proposed standby and station service rate designs we consider to be reasonable. There are also points raised by the intervenors with which we agree, and which indicate changes to CMP's proposed designs. We also will require revisions to CMP's proposal in certain other respects to be consistent with our findings in this Order. We direct CMP to develop and file in the Phase II of this case standby and station service rates using the methods summarized below. These rates will apply beginning March 1, 2000 to customers that purchase station service or standby service with loads in excess of 100 kW.

1. Station Service

CMP shall provide T&D station service to generating facilities solely engaged in the production of electricity for sale at wholesale or retail. We adopt the basic structure CMP proposes for station service whereby it will provide service to customers based upon their ratcheted demands and otherwise according to the rates and terms of the core requirements service class in which the station service customer would fall based on size and voltage level of service. We direct CMP to develop demand charges, or an adjustment factor applicable to the core class demand charge, that can apply to the ratcheted demands of station service customers consistent with the approach described in section IV(C)(4).

2. Standby Service

CMP shall provide standby service to electricity end-use customers with self-generation facilities consistent with the following:

a. Starting point

The starting point for the standby rate will be the core class revenue requirements established in this case. CMP should not reflect any discounts or reductions from core rates in the starting point.

b. Stranded cost charge

CMP should establish the stranded cost component of standby rates using a core class stranded cost allocation based on the allowed stranded cost level established in this case and the 75/25 energy/capacity allocation method described in section III(E) above. The standby rate unit charge for stranded costs will be set by dividing the core class' stranded cost allocation by the sum of the maximum customer demands, as in the method set forth in the surrebuttal testimony of Dumais, Peaco and Parmesano at Exhibit DPP-46, and charged to standby customers based on contract demand.

c. Customer charge

CMP proposes to charge standby customers the customer charge of the core rate class corresponding to the customers contract demand and voltage level of service. We adopt this aspect of CMP's proposal.

d. Transmission and distribution charge

The T&D-related costs by class shall be set by subtracting the core class stranded costs described in (b.) above and customer costs (i.e., customer charge multiplied by total customers in the class) from the starting point class revenue requirements described in (a.) above. Consistent with our discussion that a substantial portion of T&D costs are energy-related, *see* section III(B) above, 50% of these T&D amounts shall be recovered on a demand basis using a unit charge set by dividing that 50% portion by the sum of the maximum customer demands, and charged to contract demand. This is the same method set forth in the CMP surrebuttal testimony of Dumais, Peaco, Parmesano to calculate unit charges. We also adopt the time differentiation method proposed by CMP and direct the Company to develop appropriate factors to reflect diurnal differentials for the combined T&D demand charge. The remaining 50% of the T&D-related costs should be recovered on an energy basis using a unit charge set by dividing these costs by class kWh, and charging standby customers for their actual kWh usage.

The time-differentiation of the demand portion will provide a price break to standby customers that take service in lower load periods. The energy allocation provides recognition that a portion of T&D costs is energy related, effectively relieving standby customers of a substantial amount of these costs. In addition, using a kWh charge will impose a charge for incremental consumption during the month thereby discouraging wasteful use of the T&D system.

As noted above, the approach we adopt is similar to CMP's standby rate in many respects. However, it avoids reliance on CMP's marginal distribution cost estimates; as discussed in section III above, we consider those estimates to be problematic. Our approach also recognizes (in the form of lower costs for standby service) that energy usage is a significant causative factor for T&D costs.

Additionally, although not captured precisely, there is at least some recognition of diversity benefits for demand-related transmission. This is so because we begin with starting point class revenues that reflect the diversity of the core class for transmission and distribution. If we were establishing a standby rate from scratch, based on the evidence we would likely have reflected diversity benefits for transmission but not for distribution.[48]

e. KVars

CMP has proposed to charge standby customers for actual measured KVars at the applicable core rate. We adopt this aspect of CMP's proposal.

We direct CMP to develop and file in the update phase of this case a standby rate consistent with this Order.

[48]For standby customers below 400 kW it may be appropriate to add an adjustment to reflect the greater diversity benefits they should receive for distribution compared to full requirements customers. CMP should address the appropriateness of such an adjustment in its Phase II filing.

CONCLUSION

CMP is directed to make a Phase II filing consistent with the findings and conclusions contained in this Order. This filing should be made within 60 days of this Order.

Dated: December 23, 1998

Respectfully submitted,

Charles Cohen
Hearing Examiner

On Behalf of the Advisory Staff
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